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Time of Day Pricing and the Levelized Cost of Intermittent Power Generation

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Abstract:

Time of Day Pricing and the Levelized Cost of Intermittent Power Generation

An important characteristic of renewable energy sources, in particular solar and wind power, is the inherent variability in their pattern of electricity generation. These variations comprise both intra-day and seasonal fluctuations. Yet, the intermittency of renewable energy is usually ignored in life-cycle cost calculations that seek to asses the competitiveness of renewable energy in comparison to electric power derived from fossil fuels. We demonstrate that a traditional life-cycle cost calculation must be appended by a correction factor which we term the *Co-Variation* coefficient. It captures any synergies, or complementarities, between the temporal pattern of how power is generated and how it is priced. We estimate the magnitude of the Co-Variation coefficient for several specific settings in the Western U.S. Our estimates indicate that solar photovoltaic (PV) power is between 10-15% less expensive than average life-cycle cost analyses have suggested. In contrast, the intermittency pattern of wind power exhibits complementarities with electricity pricing schedules, resulting in a cost assessment that is about 5-10% above that suggested by traditional calculations.

Keywords: Renewable Energy, Intermittent Electricity, Solar PV, Wind Power, Levelized Cost of Electricity

1 Introduction

Renewable energy sources, in particular solar- and wind power, have seen impressive growth in new installations over the past decade.[1] Yet, the cost competitiveness of these renewables remains controversial, with many analysts pointing to public subsidies in the form of tax credits, accelerated tax write-offs and clean energy portfolio standards. One factor complicating the assessment of the economic viability of renewables is there intermittency, that is, the fact that wind and solar power exhibit considerable variation in their inter-temporal pattern of power generation. These variations typically pertain to both time of day fluctuations and seasonal cycles.

One approach commonly employed in the energy literature to compare the cost effectiveness of alternative power sources is the so-called *Levelized Cost of Electricity* (LCOE). This life-cycle cost concept seeks to include all cost components of a power generation facility, including upfront capital expenditures, variable and fixed operating costs and applicable taxes.[2] The LCOE is calculated as the break-even price that would have to be received *on average* per Kilowatt hour (kWh) generated in order for all costs to be covered and investors to receive an adequate return on their initial investment. In calculating this life-cycle cost figure, the vast majority of existing studies rely on average *capacity factors*, that is, the average power generated by a particular facility in any given year. For natural gas power plants, for instance, this average capacity factor is typically specified in the range of 85-90% of the maximum power available, with the remaining 10-15% accounting for scheduled maintenance. In contrast, the patterns of direct sun exposure limit the average capacity of solar PV installations to around 20-25% of theoretical capacity.

When an investor seeks to evaluate the economics of solar panels installations on a rooftop, the traditional LCOE calculation, with reliance on the average capacity factor, is still conceptually sound provided the investing party faces a flat rate per kWh that it would alternatively have to pay for obtaining power from the grid. However, if the investor faces a price schedule that varies by time of day, and possibly also by season, the traditional

[1]For instance, almost 17 Gigawatt of new photovoltaic (PV) power was installed worldwide in 2010. This addition not only represented a 250% increase relative to 2009, it was also roughly equal to the total *cumulative* amount of solar PV power installed since the commercial inception of solar PV technology in the 1970s.

[2]See, for example, EPIA (2011), Campbell (2008), Campbell (2011), Werner (2011) and Reichelstein and Yorston (2012a).

LCOE calculation will generally fail to capture any synergies that arise if the solar facility generates power above its overall average predominantly at times when electricity rates are relatively high.

Earlier literature has shown by means of examples that a levelized cost analysis may be "flawed" or "misleading" for intermittent power sources; see, for instance, Joskow (2011), Joskow (2011b) and Borenstein (2012). Specifically, Borenstein (2008) seeks to quantify the synergistic effect between fluctuations in electricity prices and the pattern of solar photovolatic (PV) power generation, suggesting a 20% bonus for this source of electricity. In contrast, the pattern of wind power generation suggests a complementarity with the daily variation in electricity prices since offshore wind tends to blow more strongly at night. Fripp and Wiser (2008) confirm this intuition and conclude that a " mark-up" factor of about 10% ought to be added to the traditional levelized cost figure for wind power.

The main point of our paper is to demonstrate that a levelized cost analysis remains appropriate for intermittent power sources, provided the cost figure obtained from a traditional average cost calculation is modified by a correction factor which we term the *Co-Variation* coefficient. As the name suggests, this coefficient captures the synergy (or complementarity) between temporal variations in electricity generation and electricity prices across times of the day and days of the year. By construction, dispatchable energy sources, like fossil fuel power plants, will always have a Co-Variation coefficient of one. One advantage of our approach is that traditional LCOE calculations, which ignore intermittency patterns of power generation, do not need to be "shelved", but instead should be appended by a correction factor obtained through the Co-Variation coefficient.

The ongoing discussion about the economics of renewable energy points out correctly that one undesirable consequence of intermittency is the need for back-up power in order to ensure grid stability. We emphasize that our analysis ignores this aspect even tough we ignore it will become increasingly prominent as renewable energy sources provide a more substantial share of the overall electricity supplied.[3]

As an application of our conceptual framework, we derive estimates for the cost impact of intermittency in connection with both solar PV and wind power. Our data pertain to facilities in the Western US. For solar power, we seek to quantify the Co-Variation effect for

[3]Dispatchable energy sources require back-up power as well in case of unscheduled plant shutdowns. One potential advantage of renewable power in this context is its decentralized base of many relatively small generation facilities.

both commercial- and utility-scale installations in central California. Our power generation data are based on simulations for the San Francisco Bay Area according to NREL's PVWatts program (NREL, 2009). The corresponding price distributions are obtained at the wholesale level from the California Independent Systems Operator (CAISO) and at the retail level from particular commercial rate schedules (A16 and E19) that Pacific Gas & Electricity (PG&E) applies to commercial customers.

The most significant daily Co-Variation coefficient in our calculations amounts to 1.79. The magnitude of this coefficient is largely attributable to the fact that PG&E charges its commercial customers up to 40 cents per kilowatt hour in the summer during peak afternoon hours. As one might expect, the overall yearly Co-Variation coefficient for this category of installations is substantially smaller and amounts to 1.17. Nonetheless, we conclude that the cost effect of intermittency is to reduce the levelized cost of electricity for commercial-scale facilities by about 15%, since $.85 = 1/1.17$. To put this finding in absolute terms, a traditional life-cycle cost calculation for commercial-scale installations in San Francisco would suggest an LCOE figure of 14.17 cents per kWh.[4] Our analysis then implies that new commercial-scale installations would be cost effective if PG&E were to charge its commercial customers at least $.85 \cdot 14.17 = 12.04$ cents on average per kWh. Thus the implied life-cycle cost effect of intermittency for this segment is a reduction of slightly more than 2 cents per kWh.

For utility-scale solar installations, we take the applicable price distribution to be wholesale prices in California. The daily variation in one-day ahead prices as posted by the CAISO is considerably smaller, both in the summer and in the winter season, than the daily variation in commercial retail rates charged by PG&E. Accordingly, we obtain a smaller Co-Variation coefficient of about 1.1, implying that the intermittency of utility-scale installations results in a favorable correction of the levelized cost by 10% relative to a traditional average cost calculation. Finally, many industry observers have pointed out that trackers have considerable potential to improve the economic viability of utility-scale solar installations, because trackers boost the capacity factor of solar panels. However, we find that trackers have no *incremental* impact on the Co-Variation coefficient. Thus our analysis suggests that the value of trackers is unrelated to the cost effect associated with intermittency.

The remainder of the paper is organized as follows. Section 2 reviews the traditional

[4]This estimate is based on the Solar PV calculator of Reichelstein and Yortson (2012b). It incorporates the tax subsidies currently available to solar PV and consistently assumes most favorable input values.

LCOE concept. In Section 3, we derive the Co-Variation coefficient and demonstrate that a traditional LCOE calculation supplemented by the Co-Variation coefficient is appropriate for intermittent power sources. Section 4 derives numerical estimates of the Co-variation coefficient for solar PV power. In Section 5, we perform a parallel analysis for wind power. Conclusions are provided in Section 6.

2 Levelized Cost of Electricity

The Levelized Cost of Electricity seeks to account for all physical assets and resources required to deliver one kilowatt hour (kWh) of electricity. Fundamentally, this concept seeks to identify a per unit break-even value that a producer would need to obtain as sales revenue in order to justify an investment in a particular power generation facility. As a consequence, the levelized product cost must be compatible with present value considerations for both equity and debt investors. In the context of electricity production, the concept introduced here is frequently referred to as the *Levelized Cost of Electricity.* In "The Future of Coal" (MIT, 2007), the authors offer the following verbal definition:
"*...the levelized cost of electricity is the constant dollar electricity price that would be required over the life of the plant to cover all operating expenses, payment of debt and accrued interest on initial project expenses, and the payment of an acceptable return to investors*".

The Levelized Cost of Electricity concept is widely used by researchers, academics and government institutions to compare the cost effectiveness of alternative energy sources which differ substantially in terms of upfront investment cost and periodic operating costs. However, the formulaic implementation of this concept has been lacking in uniformity (Reichelstein and Yorston, 2012a). In particular, some authors have conceptualized LCOE as the the ratio of "total lifetime cost" to total "lifetime electricity' produced (EPIA, 2011; Campbell, 2008, 2011; Werner, 2011). This turns out generally incompatible with the preceding verbal definition.

For a new production facility to be built, the levelized cost of one kilowatt hour aggregates the upfront capacity investment, the sequence of output levels generated by the facility over its useful life, the periodic operating costs required to deliver the output in each period, and any tax related cash flows that apply to this type of facility. Since the *output price* in question should lead investors to break-even, it is essential to specify the appropriate discount rate. Standard corporate finance theory submits that if the project in question keeps the firm's leverage ratio (debt over total assets) constant, the appropriate discount rate is the Weighted Average Cost of Capital (WACC).[5] In reference to the above quote in the MIT study, equity holders will receive "*an acceptable return*" and debt holders will receive "*accrued interest on initial project expenses*" provided the project achieves a zero Net Present Value (NPV) when evaluated at the WACC. We denote this WACC interest rate by r and the corresponding discount factor by $\gamma \equiv \frac{1}{1+r}$.

Investment in the production facility is assumed to conform to a constant returns to scale technology with the following parameters:

- SP : the construction cost (in \$ per kW),
- T : the useful life of the output generating facility (in years) and
- x_i : the capacity adjustment factor: the percentage of initial capacity that is still functional in year i.

The capacity adjustment factor reflects that in certain contexts the available output yield changes over time. For instance, with photovoltaic solar cells it has been observed that their efficiency diminishes over time. The corresponding decay is usually represented as a constant percentage factor ($x_i = x^{i-1}$ with $x \leq 1$) which varies with the particular technology. On the other hand, production processes requiring chemical balancing frequently exhibit yield improvements over time due to learning-by-doing effects, e.g., semiconductors and biochemical production processes. For base-load fossil fuel power plants, the usual specification is the "one-hoss shay" asset productivity scenario, in which the facility has undiminished capacity up to date T, that is $x_i = 1$ for all $1 \leq i \leq T$ and thereafter the facility is obsolete.

In any given year of its operation, the facility is theoretically available for 365 days. However, practical capacity is only a fraction of the capacity available due to maintenance requirements and, for many renewable energy sources, also due to the fact that the energy source is available only for a fraction of the time. Since this section seeks to develop the "traditional" LCOE concept, which ignores intertemporal variations in the capacity that available, we first represent practical capacity simply as a fixed percentage, CF, of theoretical capacity. This specification is unproblematic for a dispatachable energy source like a fossil

[5]See, for instance, Ross, Westerfield, and Jaffe (2005).

fuel. We then define the *capacity cost of capacity for one kWh* as:

$$c = \frac{SP}{365 \cdot 24 \cdot CF \cdot \sum_{i=1}^{T} x_i \cdot \gamma^i}. \tag{1}$$

To interpret c, we note that absent any other operating costs or taxes, the unit capacity cost would yield the break-even identified in the verbal definition above. For each kilowatt of initial capacity acquired at the constant per unit cost, SP, the firm expects to deliver $365 \cdot 24 \cdot CF \cdot x_i$ kWh in year t. If the average revenue per kWh were to be c , then revenue in year i would be $c \cdot 365 \cdot 24 \cdot x_i$ and the firm would exactly break-even on its initial investment over the T-year horizon.

To complete the description of the levelized product cost, let F_t denote the fixed costs incurred in operating a one kilowatt facility in year t. We assume that these fixed operating costs scale proportionally with the size of the facility. Applicable examples in this cost category include insurance, management, maintenance expenditures, and property taxes. The initial investment in capacity results in a stream of future fixed costs and a corresponding stream of future (expected) output levels. By taking the ratio of these, we obtain the following *time-averaged* fixed operating costs per unit of output:

$$f \equiv \frac{\sum_{i=1}^{T} F_i \cdot \gamma^i}{365 \cdot 24 \cdot CF \cdot \sum_{i=1}^{T} x_i \cdot \gamma^i}. \tag{2}$$

The final cost category recognized in the model comprises the variable costs of production. The applicable production inputs in this category include fuel, direct labor and supplies. Denoting by w_i the variable cost per kWh generated in year i, we define a "time-averaged" unit variable cost per kWh in the same manner as for the fixed operating costs:

$$w \equiv \frac{\sum_{i=1}^{T} w_i \cdot 365 \cdot 24 \cdot CF \cdot x_i \cdot \gamma^i}{365 \cdot 24 \cdot CF \cdot \sum_{i=1}^{T} x_i \cdot \gamma^i} = \frac{\sum_{i=1}^{T} w_t \cdot x_i \cdot \gamma^i}{\sum_{i=1}^{T} x_i \cdot \gamma^i}. \tag{3}$$

Corporate income taxes affect the levelized cost measure through depreciation tax shields and debt tax shields, as both interest payments on debt and depreciation charges reduce the firm's taxable income. While the debt related tax shield is already incorporated into the calculation of the WACC, the depreciation tax shield is determined jointly by the effective corporate income tax rate and the depreciation schedule that is allowed for the facility. These variables are represented as:

- α : the effective corporate income tax rate (in %),
- $\hat{T}$: the facility's useful life for tax purposes (in years), which is usually shorter than the projected economic life, i.e., $\hat{T} < T$,
- d_i : the allowable tax depreciation charge in year i, as a % of the initial acquisition cost SP,
- δ the investment tax credit, as a % of the initial asset value SP[6]

For the purposes of calculating the levelized product cost, the effect of income taxes can be summarized by a *tax factor* which amounts to a "mark-up" on the unit cost of capacity, c.

$$\Delta = \frac{1 - \delta - \alpha \cdot \sum_{i=1}^{\hat{T}} d_i \cdot \gamma^i}{1 - \alpha}. \tag{4}$$

The tax factor Δ exceeds 1 but is bounded above by $\frac{1}{1-\alpha}$. It is readily verified that Δ is increasing and convex in the tax rate α. Holding α constant, a more accelerated tax depreciation schedule tends to lower Δ closer to 1. In particular, Δ would be equal to 1 if the tax code were to allow for full expensing of the investment immediately (that is, $d_0 = 1$ and $d_i = 0$ for $i > 0$).

Combining the preceding cost components, one obtains the following result.

Proposition 0 *The Levelized Cost of Electricity (LCOE) is given by*

$$LPC = w + f + c \cdot \Delta \tag{5}$$

with c, w, f and Δ as given in (1) -(4).

It will be demonstrated below that the cost benchmark identified in Proposition 0 is a special case of a broader levelized cost concept that applies to settings in which production

[6] Under current tax rules, investments in solar PV installations are eligible for a 30% investment tax credit. If the investor takes advantage of this credit the applicable book value for future depreciation charges is reduced to 85% of the initial investment. In our model, this would translate to a requirement that $\sum_{i=1}^{\hat{T}} d_i = .85$.

and pricing are subject to intertemporal variations. In the current setting, the significance of the LCOE figure in (5) is that over the life-time of the facility investors break even on their investment if output sells on average for a price p greater than or equal to $LCOE$.

3 Intermittency and Time of Day Pricing

The production capacity available form the most common renewable power sources, that is, solar and wind, is subject to significant intra-day and seasonal variations . On a given day of the year, say day i, the actual capacity factor is assumed to be described by a function $CF_i(t)$, for $0 \leq t \leq 24$. As before we denote the average capacity factor by CF_i and, without loss of generality, write $CF_i(t) = CF_i \cdot \epsilon_i(t)$.[7]

Thus $\epsilon_i(t) \geq 0$ represents the percentage deviation at time t from the average capacity factor. Accordingly,

$$24 = \int_0^{24} \epsilon_i(t)dt. \tag{6}$$

To introduce intra-day variations in the market value of the electricity produced on day i, let $p_i(t)$ denote the price of electricity at a particular hour of that day. For a commercial power producer, this would be the wholesale price at which electricity can be sold to the grid operator. For an electricity consuming business or household, $p(t)$ represents the avoided cost of having to buy electricity from the grid. It will again be convenient to represent the distribution of prices as deviations from an average daily price, p_i. Thus we write: $p_i(t) = p_i \cdot \mu_i(t)$, with:

$$24 = \int_0^{24} \mu_i(t)dt. \tag{7}$$

Once electricity sales prices are no longer presumed constant, the LCOE concept developed in Section 2 requires modification so as to take into consideration for each day of the year the pattern of intra-day variations in both prices and generation capabilities. Intuitively, the life-cycle cost of electricity generation improves if the the intermittent energy

[7]Given the function $CF_i(t)$, define CF_i by:

$$24 \cdot CF_i = \int_0^{24} CF_i(t)dt.$$

The function $\epsilon_i(t)$ is then given by the ratio of $CF_i(t)/CF_i$.

source generates its output during peak price periods. This suggests the following measure of Co-Variation between prices and kilowatt hours generated.

Definition 1: *The Co-Variation coefficient between $CF_i(t)$ and $p_i(t)$ on day i is given by:*

$$\Gamma_i = \frac{\int_0^{24} \epsilon_i(t) \cdot \mu_i(t) dt}{24} \tag{8}$$

By construction, the Co-Variation coefficient is non-negative and would be zero only in the extreme case where the facility generates electricity at times when the price is zero. It is instructive to consider the following two "corner" cases. First, with uniform pricing, that is, $p_i(t) = p_i$, the coefficient Γ_i will always be equal to 1, regardless of the capacity pattern, $CF_i(t)$. Conversely, $\Gamma_i = 1$, whenever the power source is effectively dispatchable in the sense that $CF_i(t) \equiv CF_i$. These observations suggest that 1 is the benchmark value for an intermittent power source to exhibit *value synergies* with the time of use pricing pattern.

Since there are $365 \cdot 24 = 8,760$ hours in a year, we obtain the annual price distribution $p(\cdot)$ defined on the range $[0, 8760]$ by "stitching together" the individual $p_i(t)$. Clearly, the mean value of $p(\cdot)$ is given by:

$$p = \frac{1}{365} \sum_{i=1}^{365} p_i.$$

In stating the following result, we refer to a power generating facility that faces the price distribution, $p(\cdot)$ with mean value p as *cost competitive* if the present value of all after-tax cash flows received or paid over the lifetime of the facility is non-negative. Finally, the aggregate or annual Co-Variation coefficient is defined as the arithmetic mean of the daily coefficients:

$$\Gamma = \frac{1}{365} \sum_{i=1}^{365} \Gamma_i.$$

Proposition 1 *The intermittent power generation facility is cost competitive if and only if:*

$$\Gamma \cdot p \geq LCOE.$$

The proof of Proposition 1 is provided in the Appendix. The result shows that a traditional LCOE analysis, which "glosses" over variations in the intertemporal distribution of electricity prices, needs to be appended by the Co-Variation coefficient. In particular, the cost competitiveness of a power generation facility can still be expressed succinctly by means of the average life-cycle cost, $LCOE$, provided this figure is scaled by Γ. Our finding puts perspective on the critique articulated by Joskow (2011). While the conceptual limitations of a traditional LCOE analysis for measuring the competitiveness of intermittent power sources are uncontroversial, our focus on the coefficient Γ allows for a direct quantification of how "flawed" (Joskow, 2011, page 2) the LCOE metric actually is. In particular, our finding suggests that the many life-cycle cost analyses that have been performed for a wide range of renewables in different geographies only need to be augmented rather than redone from scratch.

As observed above, $\Gamma = 1$ if either prices are uniform or the capacity factor is constant. Thus, both intermittency and time of use pricing are required in order to render a traditional LCOE analysis incomplete. We next identify sufficient conditions for the Co-Variation coefficient Γ to exceed 1. The straightforward intuition here is that the two distributions $\epsilon_i(\cdot)$ and $\mu_i(\cdot)$ concentrate a significant portion of their respective mass on a common daily time interval.

Proposition 2 *Suppose both $\epsilon_i(\cdot)$ and $\mu_i(\cdot)$ are continuous, single-peaked functions that reach their maximum at a common time t^*, $0 \leq t^* \leq 24$. Then $\Gamma \geq 1$ provided either of the following two conditions is met:*
i) $\epsilon_i(\cdot)$ is symmetric around $t^* = 12$,
ii) both $\epsilon_i(\cdot)$ and $\mu_i(\cdot)$ are symmetric.

It is readily seen that some symmetry condition will be required beyond the condition of a common peak-time in order to conclude $\Gamma \geq 1$. To illustrate, Γ would in fact be zero in case both $\epsilon(\cdot)$ and $\mu(\cdot)$ are rectangular distributions, such that $\epsilon(\cdot) = 2$ on the interval $[0, 12]$, while $\mu(\cdot) = 2$ on the interval $[12, 24]$.

The assumption of two single-peaked distributions both of which attain their maximum at a common time t^* appears reasonably descriptive for solar PV installations, in particular in jurisdictions where the power used by afternoon air conditioning is a significant demand factor. Insofar, we would expect solar PV to exhibit a Co-Variation coefficient greater than 1. In contrast, the sufficient conditions identified in Proposition 2 do not seem applicable to wind power, an observation that is consistent with the intuition that recognition of intermittency will cause wind power to be assessed as costlier than suggested by an average cost calculation. The following section seeks to estimate the magnitude of Γ for both of these power sources.

We conclude this section by noting that the conceptual approach developed in this section can easily be extended to settings in which the distribution of prices , $p(\cdot)$ is expected to change across years. If the useful life of the facility is $T = 25$, the overall life-cycle Co-Variation coefficient would be obtained by "stitching together" the 25 annual price distributions. The overall life-cycle Co-variation coefficient would then be obtained as the arithmetic mean of the individual yearly coefficients identified in this section.

4 Estimating the Co-Variation Coefficient: Solar PV Power

This section derives estimates for the Co-Variation coefficient associated with solar PV power projects. Our analysis distinguishes between coefficients relevant to utility- and commercial-scale solar projects. We focus on installations that are in the service territory of the Pacific Gas& Electricity Company. Though retail rates for most industrial and commercial customers in PG&E service territory change based on the time of day, day of the week and season, these fluctuations are not necessarily aligned with the variation in the wholesale price of electricity.[8] The observed differences in the fluctuations of wholesale and retail prices suggest that the Co-Variation coefficients for utility-scale and commercial-scale solar installations may differ significantly.

Our focus below is on annual Co-Variation coefficients. In accordance with our framework in Section 3, we calculate 365 daily Co-Variation coefficients and then report the relevant averages.[9] For each day, we thus use the day-specific simulated generation data to derive a day-specific ϵ_i(t) and either the applicable wholesale prices or retail price schedule to derive day-specific μ_i(t) vectors. While the ϵ_i(t) are the same for utility and commercial-scale installations, μ_i(t) will differs by the type of solar PV facility.

[8]Real-time pricing provides a retail pricing structure that varies with wholesale prices, but it is not widely used.

[9]Though we use 2012 wholesale price data, with 366 days of data, the PVWatts simulation provides generation data for a non-leap year. We consequently do not use price data from February 29, 2012.

4.1 Solar PV Power Generation

Before presenting our estimates of the solar PV Co-Variation coefficients, we describe the generation data we use and our estimation method. We use the PVWatts calculator available from the National Renewable Energy Laboratory to simulate a year of generation data (NREL, 2009). We ran this simulation for a PV facility in San Francisco, CA, assuming modules with an 85% DC-to-AC derate factor. Our data provide for each day within a year simulated hourly generation data. We ran the simulation twice: once assuming fixed tilt tracking arrays and again assuming 1-axis tracking arrays. The data from each simulation include 8,760 (365 days $*$ 24 hours/day) distinct simulated generation values. Figures 1 and 2 below provide example summer and winter generation curves for fixed tilt tracking arrays. Note that these examples are for particular days but that we actually used 365 such curves in our analysis.

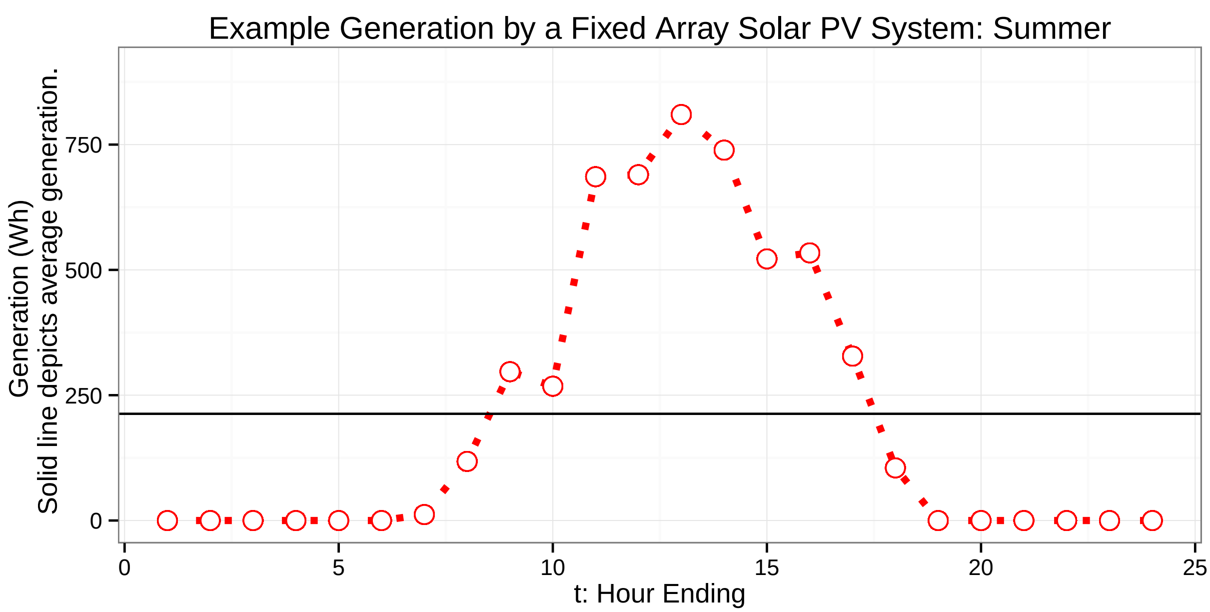

Figure 1: Example generation curve for a fixed tilt array in San Francisco, CA (summer), assuming a 1kW installation.

As one would expect, the generation pattern for the "representative" summer day results in substantially higher capacity with an average capacity factor of about 24% compared to about 10% for the representative winter day. In addition, the temporal variation in power generated, relative to the mean, also appears substantially higher during the summer. For

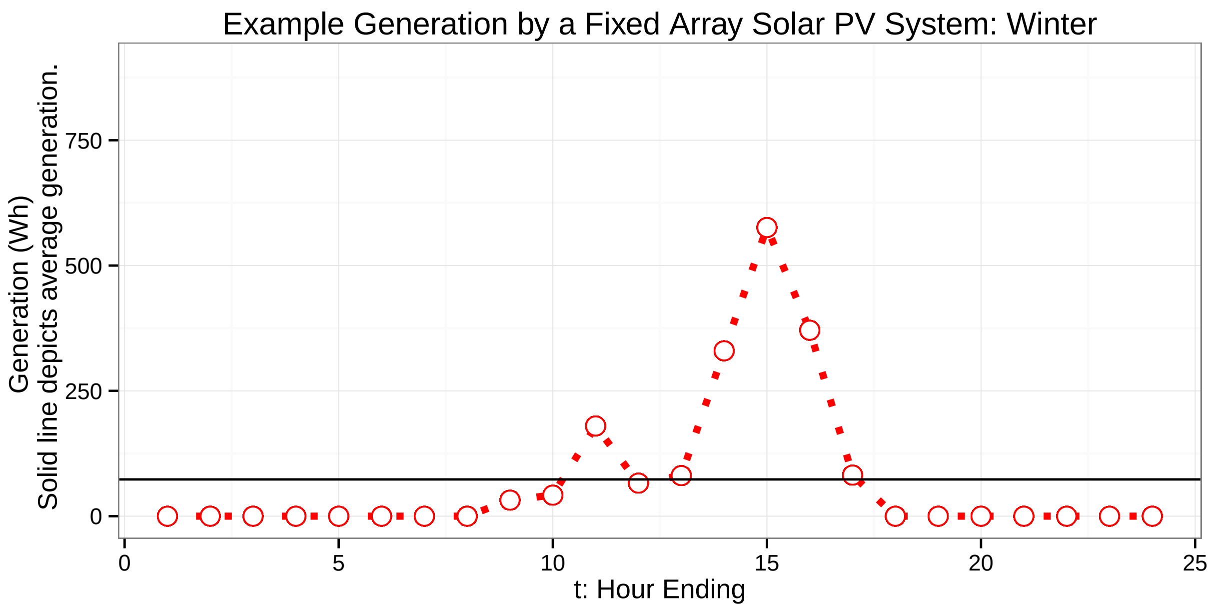

Figure 2: Example generation curve for a fixed tilt array in San Francisco, CA (winter), assuming a 1kW installation.

either daily distribution, we obtain the percentage deviations from the mean, that is, the curve $\epsilon_i(t)$ as the ratio between $CF_i(t)$ and the mean capacity factor CF_i on that day.

4.2 Commercial-Scale Installations: Small Commercial Customers

Commercial-scale solar PV projects refer primarily to rooftop solar PV generating facilities installed by firms (e.g., on warehouse, factory or retail store rooftops). Since the firms that install these projects can use the power generated to avoid the cost of purchasing electricity from the utility company, we use retail rate schedules to derive the price distribution $p(t)$, introduced in Section 3, and the corresponding distribution of percentage deviations from the mean, p, represented by μ(t).[10] Specifically, we use rate schedules from the Pacific Gas and Electric Company, as it is the investor-owned utility that serves northern California, the area for which we obtain simulated generation data.

[10]Whenever relevant, we use secondary voltage prices. Our results would not materially differ if we were to use primary voltage prices, but transmission voltage prices within the schedules we consider have smaller absolute and relative differences between peak and part-peak and part-peak and off-peak prices than do the secondary and primary voltage price schedules. We thus expect that the Co-Variation coefficient would decrease upon substituting transmission voltage prices for secondary voltage prices. We define peak, part-peak and off-peak periods in the main text.

Commercial electricity rates differ not only by the period of the day during which the energy is consumed, but also by the season of purchase. PG&E divides the year into two seasons: the summer, which includes the period between May and October, inclusive, and the winter, which includes all other months. Regardless of season, electricity consumed during weekend and holiday days are billed at off-peak rates, so commercial customers pay the relevant season's off-peak price during all hours of these days.[11]

A commercial customer is considered to be small if the maximum power demand is below 500kW. These customers in the PG&E service area requently elect the A-6 electricity price schedule (PG&E, 2010a).[12] The A-6 price schedule does not include so-called demand charges, and the rate structure is thus such that PG&E recoups the cost of serving such customers solely through energy charges. These energy charges are consequently uniformly higher than those in other commercial rate schedules, like the E-20, which we examine in Section 4.3.

Figure 3 shows the time-of-use pricing schedule for commercial customers on the A-6 price schedule.[13] Most striking here is that during the peak period prices reach a plateau level of $0.44/kWh for six hours.

Comparing Figure 3 with Figure 1 above, it is transparent that the times of highest prices are strongly correlated with the periods of highest solar generation. As a consequence, the Co-Variation coefficient for customers on the A-6 price schedule hits a high of 1.61 during the summer season. In contrast, the average winter Co-Variation coefficient for customers on the A-6 rate is 1.05. Again, the price schedule is instructive, and Figure 4 displays the winter A-6 pricing schedule. In contrast to the summer schedule, the winter prices remain within a much tighter region around the average price of $0.1402/kWh.

[11]PG&E defines eight holiday days, and these are Near Year's Day, President's Day, Memorial Day, Independence Day, Labor Day, Veterans Day, Thanksgiving Day and Christmas Day.

[12]Small commercial customers could also elect the A-10 or E-19 rates. Those with demand equal to or greater than 499kW for three consecutive months are transferred to Schedule E-19 or E-20; the latter is generally used by customers whose maximum demand exceeds 1,000kW (PG&E, 2010b). Moreover, those with demands lower than 199kW for 12 consecutive months are eligible to elect a non-time-of-use rate schedule. Note that a solar pilot program increases the maximum demand limit for A-6 customers to 1,000kW, but a customer must not have more than 20MW of installed solar capacity. The solar PV system must meet at least 20% of the measured maximum demand of such customers electing the A-6 rate. The pilot program is by application only and is open to a limited number of customers.

[13]Note that Figures 3 and 4 show weekday prices. On weekends and holidays, the prices are fixed at the relevant season's off-peak rate.

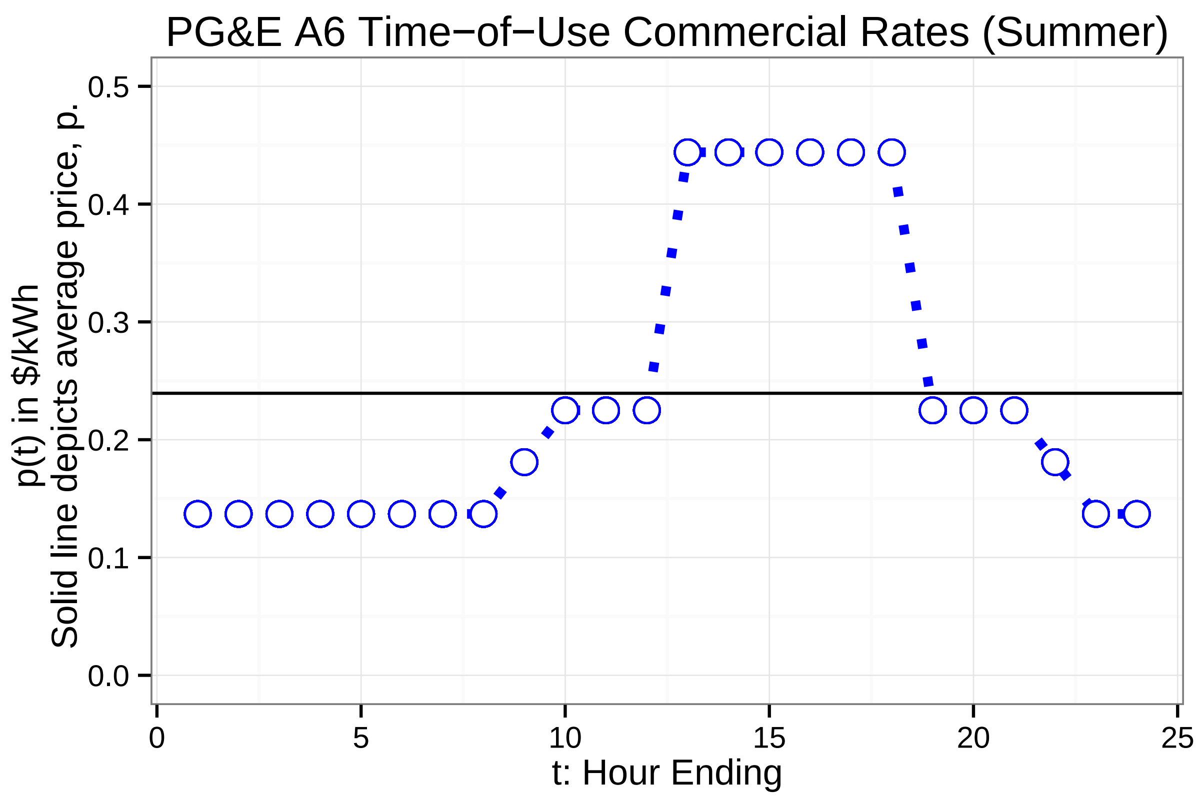

Figure 3: Example PG&E A-6 Time-of-Use price curve (summer)

Combining the summer and winter data, we obtain the following yearly average Co-Variation coefficient for customers on the A-6 rate schedule.

Proposition 3 *For customers on the A-6 electricity rate schedule, our estimate for the yearly average Co-Variation coefficient is* $\Gamma = 1.17$.

To put this finding in context, Reichelstein and Yorston (2012a) report a traditional average LCOE calculation that ignores the temporal co-variation between prices and solar power generation). Assuming most favorable parameter configurations, in particular recent prices for solar panels, they obtain a levelized cost estimate of \$0.1217/kWh. This estimate assumed a 17.70% DC-to-AC capacity factor, given the authors' assumption of a most favorable location. Since San Francisco is not as favorable of a location for solar PV generation, we use a San Francisco DC-to-AC capacity factor of 17.07% and Reichelstein and Yorston (2012b) to derive a broad-average LCOE of \$0.1417/kWh.[14] Applying the average

[14]We arrive at the 17.07% capacity factor by examining the ratio of simulated generation in San Francisco

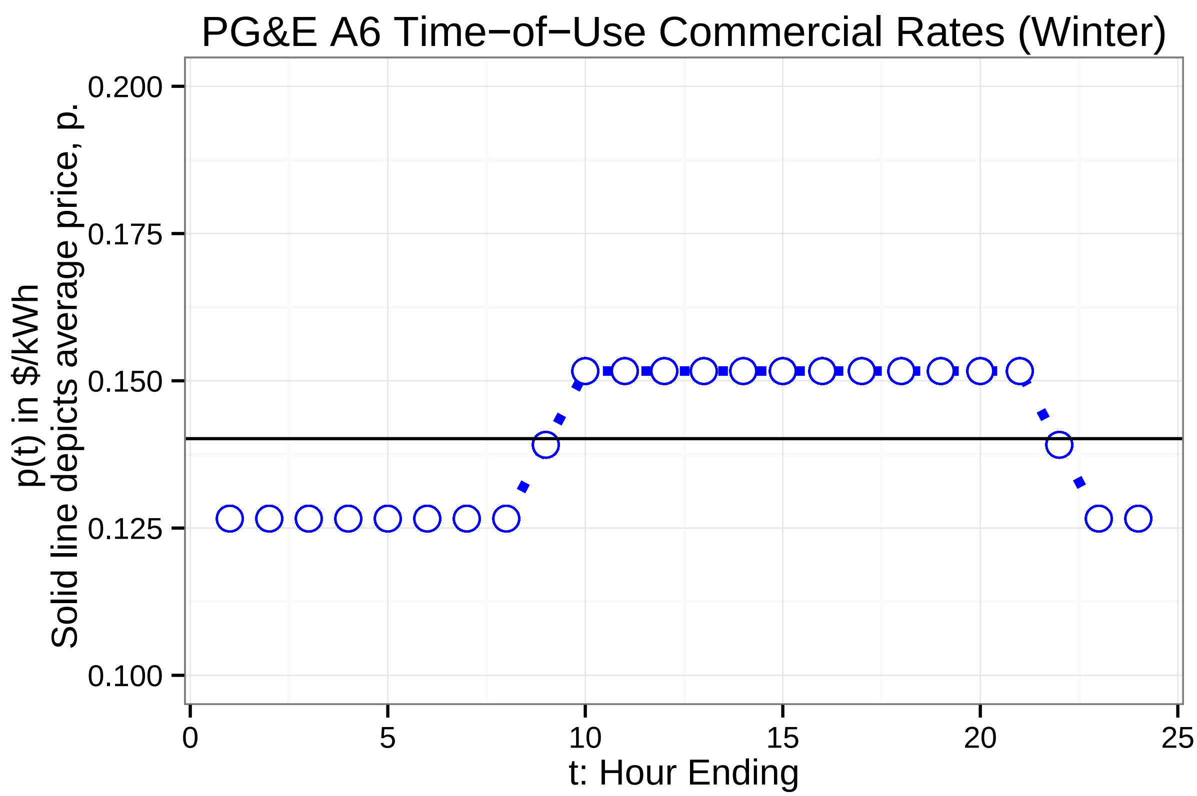

Figure 4: Example PG&E A-6 Time-of-Use price curve (winter)

Co-Variation coefficient to this estimate, our calculations suggest an adjusted levelized of \$0.1211/kWh. Thus, for commercial customers on the A-6 tariff, the adjustment in the LCOE due to intermittency results in an approximately \$0.02/kWh lower cost figure.

4.3 Commercial-Scale Installations: Large Commercial Customers

We now shift our attention to the Co-Variation coefficients relevant to larger commercial customers, or those with a maximum electricity demand of at least 1,000kW.[15] Retail electricity rates for large commercial customers often include both a fixed charge, known as the demand charge, and a variable charge, known as the energy charge.[16] The demand charge

to that in San Diego, as provided by PVWatts.

[15]We derive essentially the same results for medium-sized customers (those with maximum demands between 499 and 999kW) on the PG&E E-19 electricity rate schedule.

[16]Note that there are other fixed charges that do not scale in any way with the customer's size. For example, customers are charged a daily meter charge. Note also that we do not account for any responsiveness by customers to Peak Day Pricing (PDP) credits. Peak Day Pricing events are called when electricity supply is

is based on the customer's maximum demand (i.e., electrical load) each month: the utility company measures the quantity of energy demanded by the customer every 15 minutes (in kilowatts (kW)), and the highest 15 minute average in a month is used as the customer's maximum demand (PG&E, 2010a).

On time-of-use rate schedules, the maximum demand is measured separately for peak, part-peak and off-peak periods of the day, with the demand charge highest during peak and lowest during off-peak periods.[17] The energy charge is billed on the basis of the actual amount of power consumed, as measured by the kilowatt hours of electricity consumed by the customer at different times of the day. On time-of-use rate schedules, the energy charge is higher during peak and part-peak periods than on the off-peak period. Other utilities have different pricing structures, and their structures may yield coefficients that differ from those reported here.[18]

To derive the Co-variation coefficients for large commercial customers, we use the same generation patterns as those illustrated by Figures 1 and 2 but prices are now based on the so-called E-20 rate schedule (Figure 5). The average summer Co-Variation coefficient for customers on the E-20 rate is 1.16 and the maximum coefficient during the summer season is 1.32. Figure 5 below illustrates the E-20 summer pricing schedule. The higher prices during the peak period account for the coefficient attaining a value greater than one; since the peak period increase is not as pronounced as it is for customers on the A-6 rate, we logically derive an average summer Co-Variation coefficient lower than that found for customers on the A-6 rate.

expected to be tight. During these events, retail customers are charged a higher price but are provided with rebates if they are able to reduce their electricity consumption below a baseline amount that is derived from historical consumption data. See, for example, PG&E (2010a). Small and medium commercial customers will be automatically transitioned to rates including PDP pricing in November 2014.

[17]Within PG&E territory, the summer months include peak, part-peak and off-peak periods. While the peak and off-peak periods cover the times during which demand is highest, the part-peak period covers times of intermediate demand. Since demand in PG&E territory tends to be highest in the summer months due to cooling demand, and since the winter climate is mild across most of the utility's service territory, the winter months are characterized by part-peak and off-peak periods, only.

[18]For example, Southern California Edison (SCE) Schedule TOU-8, which applies to non-residential customers whose monthly maximum demand equals or exceeds 500 kW, pay energy charges of $0.14961/kWh and $0.05984/kWh during summer peak and off-peak periods, respectively (SCE, 2011). In contrast, customers on the PG&E Schedule E-19, which applies to non-residential customers with monthly maximum demands between 499kW and 999kW, pay $0.13357/kWh and $0.06978/kWh during the same periods, respectively (PG&E, 2010b).

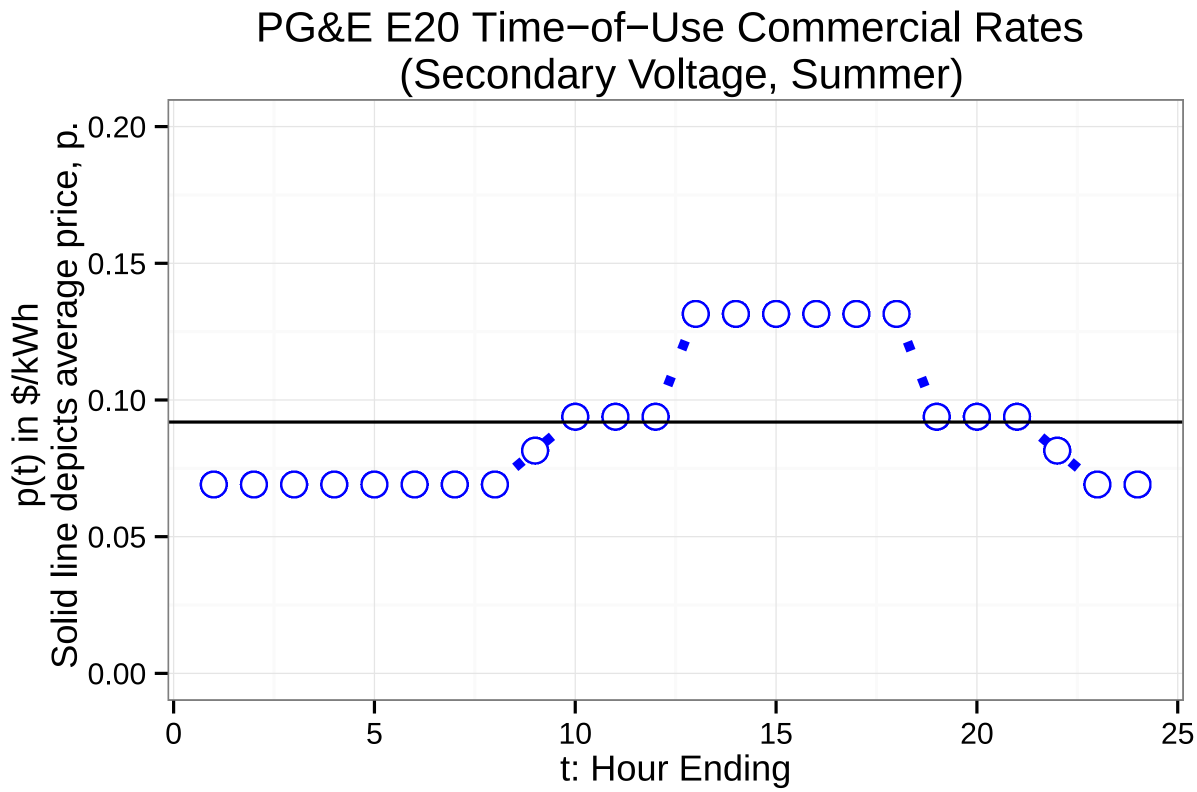

Figure 5: Example PG&E E-20 Time-of-Use price curve (summer)

The winter E-20 price schedule is depicted in Figure 6 below. Analogous to the A-6 schedule, prices remain very close to the average price of $0.0801/kWh, and we find an average winter coefficient of 1.07. This is slightly larger than the average winter A-6 Co-Variation coefficient; while the absolute difference between the peak and average prices is greater for the A-6 schedule, the E-20 schedule implies a greater *relative* increase between peak and average prices and therefore a greater $\mu(t)$. The relative proximity of the A-6 and E-20 average winter Co-Variation coefficients reflects both a lower variation in prices during the winter season and a lower degree of temporal overlap between periods of high solar generation and high prices relative to the summer season. Heating loads tend to be highest during off-peak evening and morning hours; at this time, solar PV generation is equal or close to zero, and the actual pricing schedule has little impact on the overall Co-Variation coefficient.

Combining the summer and winter data, we find the following yearly average Co-Variation coefficient for customers on the E-20 rate:

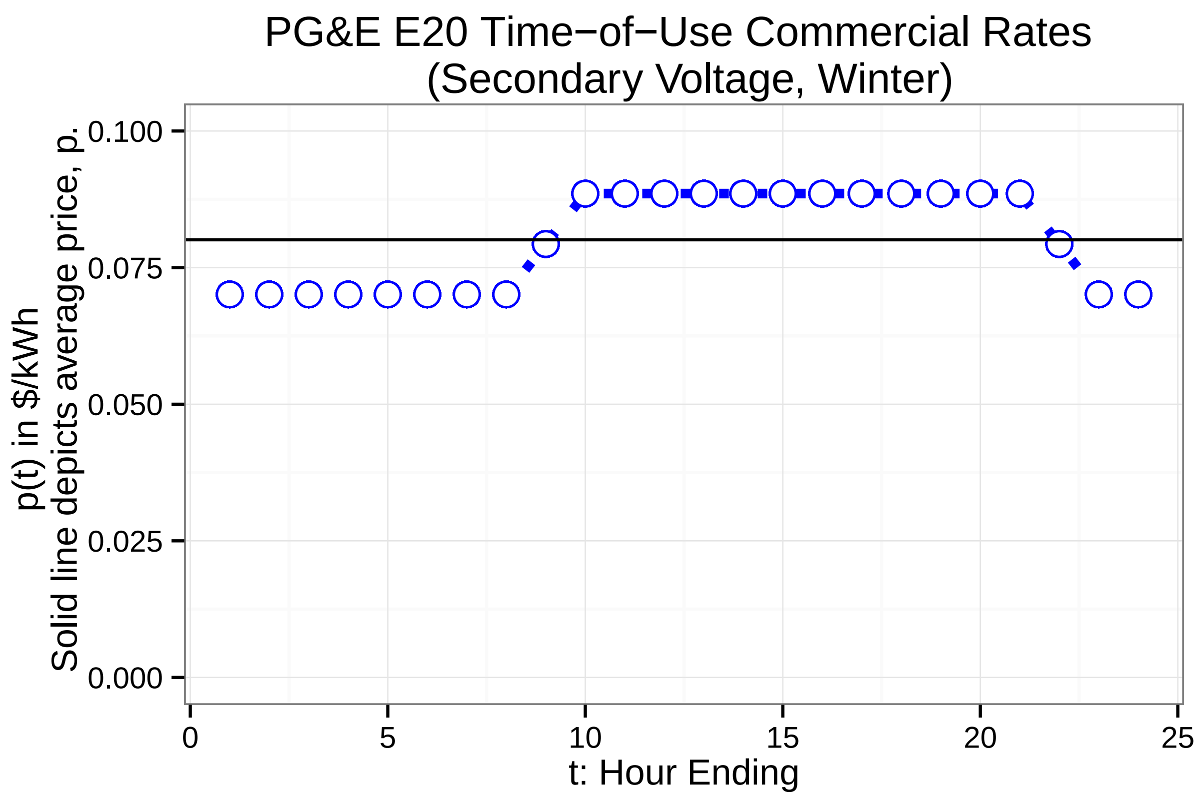

Figure 6: Example PG&E E-20 Time-of-Use price curve (winter)

Proposition 4 *For customers on the E-20 electricity rate schedule, our estimate for the yearly average Co-Variation coefficient is* $\Gamma = 1.11$.

Our finding in Proposition 4 should be interpreted as a lower bound on the Co-Variation coefficient, as we focus only on energy charges. The existence of time-varying demand charges implies weakly higher Co-Variation coefficients than those we derive here, since any reduction in demand attributable to solar PV generation during periods with higher demand charges would increase the Co-Variation coefficient beyond the value we calculate upon including only energy charges. For the E-20 schedule, the summer demand charge is $11.68/kW for off-peak demand but $15.72/kW for peak demand. If a solar installation can reduce power demand preferentially at peak times, the implied Co-Variation coefficient would be higher than the one derived in Proposition 4. However, since demand reductions cannot be guaranteed without storage, we conservatively do not account for any reduction in demand charges.

Upon applying our estimated Co-Variation coefficient from Proposition 4 to adjust the traditional average LCOE for San Francisco based on Reichelstein and Yorston (2012b), we obtain an adjusted levelized cost figure of \$0.1276/kWh. For commercial customers on the E-20 tariff, the resulting LCOE adjusted by the Co-Variation coefficient yields a cost reduction of approximately \$0.014/kWh.

4.4 Utility-scale Installations

In this section, we estimate Co-Variation coefficients relevant to utility-scale solar installations. While we again use the same hourly generation data as in Section 4.1., we now use wholesale price data from the California Independent System Operator (CAISO) Day-Ahead Market (CAISO, 2012). The CAISO Day-Ahead Market is structured around three zones: the NP15, ZP26 and SP15, with the first covering electricity nodes in northern California, the middle, areas around the metropolitan Los Angeles area and the last, those in southern California. Since we will consider solar PV installations in the San Francisco area, we use marginal price data for the NP15 zone.[19].

Unlike the commercial-scale applications which have deterministic pricing structures that differ only by season, wholesale prices are determined by an hourly balancing of supply from generators with demand from customers. Thus, while on weekend and holiday days, commercial retail prices are held fixed at off-peak prices, wholesale prices display a greater degree of variability. Figure 7 below provides an example of marginal prices observed during the summer of 2012. In calculating utility-scale Co-Variation coefficients, we now use 365 different daily price curves, as observed in the CAISO Day-Ahead Market.

The average summer Co-Variation coefficient for utility-scale investments is 1.17, and the highest observed coefficient is 1.43. The similarity between the summer average and the analogue reported for commercial customers on the E-20 rate masks differences in the distribution of the coefficient across commercial and utility-scale projects. The fixed price schedule of the commercial-scale E-20 rate implies a bimodal distribution of summer Co-Variation coefficients, with one mode at 1.00, corresponding to steady off-peak prices during weekend and holiday days, and another at approximately 1.22, corresponding to the fixed

[19] In particular, we use the NP15 localized marginal prices for energy. We thus explicitly value the energy content of the solar generation independent of system loss and congestion effects that are separately priced and bundled with the localized marginal price for energy to derive the total locational marginal price.

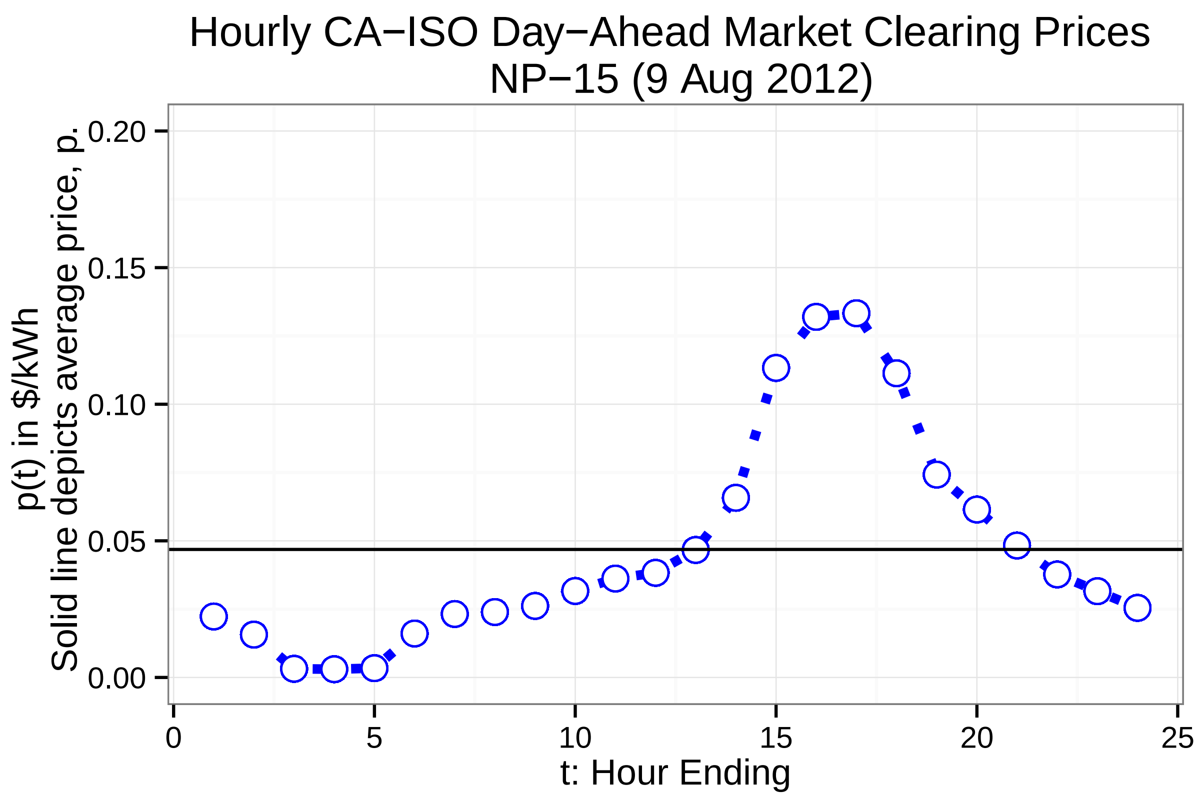

Figure 7: Example CAISO NP15 Day-Ahead Market wholesale price curve (summer)

weekday pricing structure. In contrast, the utility-scale summer coefficient distribution appears nearly normally distributed, with a mean of 1.17 and a standard deviation of 0.07.

Figure 8 provides an example of marginal prices observed during the winter periods of 2012, and we calculate an average winter Co-Variation coefficient of 1.05. Again, the similarity between the commercial and utility-scale coefficients masks heterogeneity in the distribution of the coefficient. While the coefficient never dips below 1.00 for the commercial rate structures, the utility-scale solar PV Co-Variation coefficient attains a minimum value of 0.87, implying that our Co-Variation coefficient adjustment sometimes implies that the daily break-even price for solar PV projects is *higher* than the traditional LCOE metric suggests. However, the utility-scale Co-Variation coefficient achieves a value lower than 1 in only 39 days during the observed 2012 data; almost all of these were winter days, when $\mu(\mathrm{t})$ tended to achieve its highest values during the evening and morning hours.

We obtain the following yearly average Co-Variation coefficient for utility-scale installations:

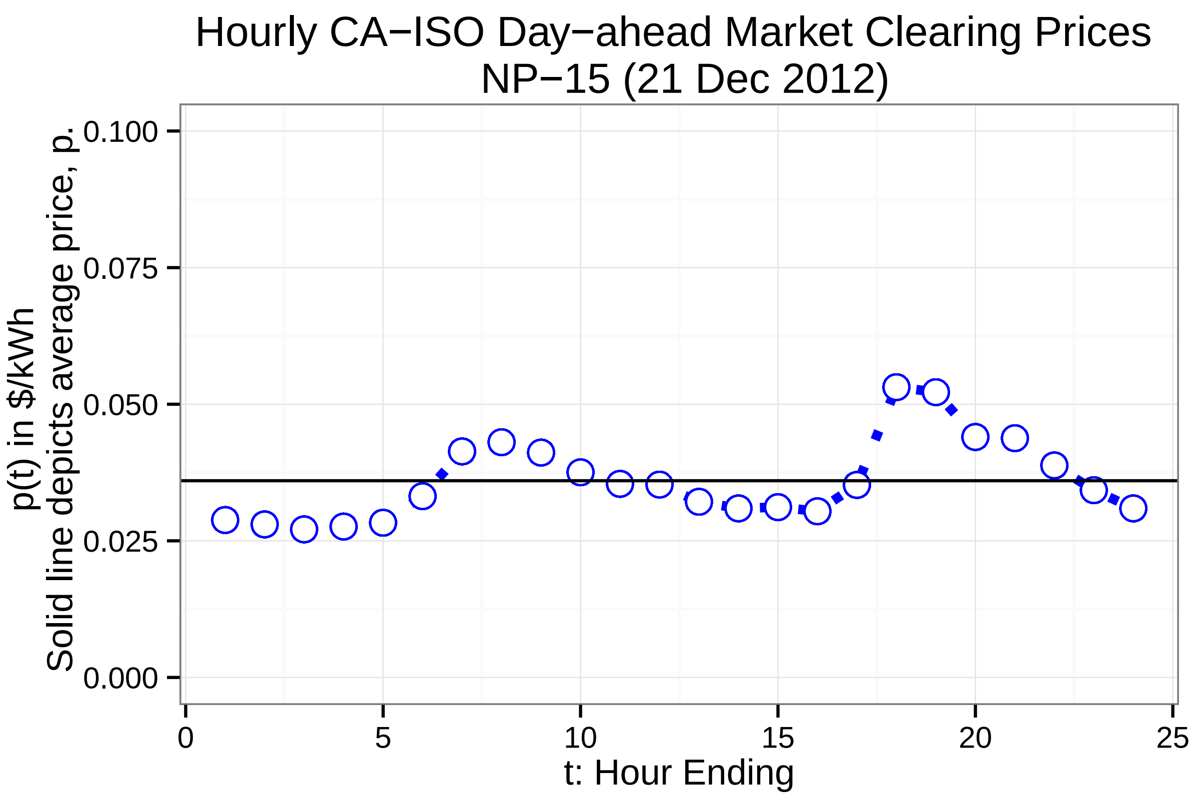

Figure 8: Example CAISO NP15 Day-Ahead Market wholesale price curve (winter)

Proposition 5 *For utility-scale solar installations, our estimate for the yearly average Co-Variation coefficient is* $\Gamma = 1.11$.

Reichelstein and Yorston (2012a) estimate a utility-scale LCOE of \$0.0797/kWh. This estimate assumed a 19.87% DC-to-AC capacity factor; we use a San Francisco DC-to-AC capacity factor of 19.17% and Reichelstein and Yorston (2012b) to derive a traditional LCOE of \$0.0826/kWh. Applying the Co-Variation coefficient to this estimate, our calculations suggest an adjusted levelized cost of \$0.7441/kWh which accounts for the synergies between power generation and wholesale prices.

Our broad-averaging calculations based on Reichelstein and Yorston (2012b) implied a \$0.0591/kWh difference in commercial and utility-scale LCOEs. Upon adjusting the LCOEs by the derived Co-Variation coefficients, the difference between commercial and utility-scale LCOEs drops to \$0.0467/kWh and \$0.0532/kWh for customers on the A-6 and E-20 rates, respectively. The Co-Variation coefficient both deflates the LCOE for commercial and utility-scale customers and reduces the absolute difference in LCOEs between the two solar applications.

We finally comment on the degree to which the use of traditional LCOE properly reflects the value of trackers for solar PV systems. Intuitively, an average LCOE calculation for a tracking PV system may fail to capture a higher or lower co-variation between generation and energy prices relative to fixed-axis systems. Table 1 documents our estimated Co-Variation coefficients for utility-scale fixed-axis and one-axis tracking solar PV systems.

	Γ, Utility, Fixed-Axis	Γ, Utility, One-Axis Tracking
Yearly	1.11	1.11
Minimum	0.87	0.87
Maximum	1.43	1.58
Summer	1.17	1.18
Winter	1.05	1.05

Table 1: Average yearly, summer and winter and minimum and maximum observed Co-Variation coefficients for utility-scale fixed-axis or one-axis tracking solar PV projects

Table 1 suggests that the Co-Variation coefficient does not differ markedly between the fixed-axis and one-axis tracking solar PV options. While one-axis tracking systems increase the magnitude of the generation, they do not appreciably shift patterns of generation to coincide with times of higher electricity prices. Thus, the higher capacity factor of one-axis tracking systems already captures most of the benefits of the technology relative to fixed-axis systems. Upon adjusting the LCOE of both fixed-axis and one-axis solar PV projects, the potential LCOE reduction from the use of trackers decreases from the 10% estimate provided by Reichelstein and Yorston (2012a). We summarize our findings in the following Corollary to Proposition 5:

Corollary to Proposition 5 *Solar PV systems with trackers exhibit the same yearly Co-Variation coefficient equal as their fixed axis counterparts.*

The preceding finding says that trackers appear to shift the distribution of generation uniformly upward but not by an incrementally greater amount at times of higher prices.

5 Estimating the Co-Variation Coefficient: Wind Power

Under construction....

6 Conclusion

The continued global growth in renewable energy sources makes it essential to assess the relative cost competitiveness of these energy sources. A traditional Levelized Cost of Electricity (LCOE) metric appears incomplete since it only reflects average capacity factors and average electricity prices, thereby effectively ignoring the intermittency of renewable power. The conceptual contribution of our analysis is that a traditional LCOE analysis remains valid for intermittent power sources, provided the average cost figure is supplemented by a Co-Variation coefficient that captures any synergies (or complementarities) in the daily patterns of how power is generated and how it is priced in the market.

Upon applying the Co-Variation coefficient to solar PV and wind power facilities in the western U.S., we estimate that the adjusted LCOE for solar PV projects is 10% to 15% lower than suggested by traditional average cost calculations, while the adjusted LCOE for wind projects is roughly 4% to 10% higher than the unadjusted version. The traditional LCOE based on averages only thus undervalues solar PV projects, but overvalues wind projects.

For small commercial customers in Central California, we estimate an average yearly Co-Variation coefficient of 1.17 Upon applying this Co-Variation coefficient to unadjusted LCOE estimates based on Reichelstein and Yorston (2012b), the average LCOE figure is reduced by $0.02/kWh. For large commercial customers evaluating an investment in solar PV facilities, we estimate a yearly Co-Variation coefficient of 1.11, thus resulting in an adjusted LCOE that is $0.014/kWh lower than the unadjusted version.

The estimated Co-Variation coefficient for utility-scale investments is based on wholesale prices rather than commercial retail rates. Nonetheless our estimates for utility-scale investments match those for large commercial-scale installations. Furthermore, our simulation data suggest that trackers shift the distribution of power generation uniformly upward but not incrementally more at times of higher prices. As a consequence, we conclude that the inclusion of trackers, while generally a valuable option for many utility-scale projects, does not have a measurable incremental impact on the Co-Variation coefficient relative to fixed-axis solar PV systems.

A promising extension of our current framework will be to examine the inclusion of electricity storage systems for commercial-scale and utility-scale facilities. While currently available storage systems are likely to entail a tangible increase in the traditional LCOE, they also entail two offsetting benefits. First, storage systems could be a means of allowing businesses to reduce the fixed demand charges described in Section 4. Secondly, power generated could be first stored and then released at times of greatest value. Finally, the inclusion of storage capabilities would obviously also be of importance in limiting the potential costs associated with renewables in terms of grid stability.

7 Appendix

Proof of Proposition 1:

At time t in year j the operating revenue per kilowatt of power installed is given by:

$$Rev_j(t) = x_j \cdot CF(t) \cdot p(t).$$

Here $p(t)$ is the price distribution on the range $[0, 8760]$ obtained by "stitching together" the 365 daily price distributions $p_i(t)$. Since each one of these integrates out to $24 \cdot p_i$ and the overall annual average price p was defined as:

$$p = \sum_{i=1}^{365} \frac{p_i}{365},$$

we have:

$$8760 \cdot p = \int_0^{8760} p(t)dt. \tag{9}$$

For notational brevity, we define $m \equiv 8760$. The overall pre-tax cash flow in year j per kW of power installed then becomes:

$$CFL_j^o = x_j \int_0^m [p(t) - w_j] \cdot CF(t)dt - F_j$$

The firm's taxable income in year j is given by:

$$I_j = CFL_j^o - SP \cdot d_j$$

The investment in on kW of power is cost competitive if, and only if, the present value of all after-tax cash flows is non-negative, that is:

$$\sum_{j=1}^{T} \quad CFL_j \cdot \gamma^j - SP(1 - \delta) \geq 0, \tag{10}$$

where CFL_j denotes the after-tax cash flow in year i:

$$CFL_j = CFL_j^o - \alpha \cdot I_j.$$

Direct substitution shows that (10) holds if and only if:

$$(1 - \alpha) \sum_{j=1}^{T} [\int_0^{365} x_j \; [p(t) - w_j] \cdot CF(t)dt - F_j] \; \gamma^j \geq \alpha \cdot \sum_{j=1}^{T} SP \cdot d_j \cdot \gamma^j + SP \; (1 - \delta). \tag{11}$$

Dividing by $(1-\alpha)$ and recalling the definition of the tax factor:

$$\Delta \equiv \frac{1-\delta-\alpha\cdot\sum_{j=1}^{T} d_j\gamma^j}{1-\alpha},$$

the inequality in (11) reduces to:

$$\sum_{j=1}^{T} x_j [\int_0^m x_j \,[p(t)-w_j]\, CF(t) - F_j]\,\gamma^j \geq SP\cdot\Delta. \quad (12)$$

In direct analogy to the definition of the annual price distribution $p(\cdot)$, we define $CF(\cdot)$ on the interval $[0,m]$ by "stitching together" the daily $CF_i(t)$. Recalling that $p(t) \equiv p\cdot\epsilon(t), CF(t) \equiv CF\cdot\mu(t)$, it follows that:

$$\int_0^m \epsilon(t)\;dt = \int_0^m \mu(t)\;dt = m,$$

Thus inequality (12) holds provided

$$p\cdot\int_0^m \epsilon(t)\cdot\mu(t)dt \geq \frac{\sum_{j=1}^{T} x_j\cdot\gamma^j\cdot m\cdot w_j\cdot CF + \sum_{j=1}^{T}\gamma^j\cdot F_j + SP\cdot\Delta}{CF\cdot\sum_{j=1}^{T} x_j\cdot\gamma^j}. \quad (13)$$

Recalling the definition of the daily Co-Variation coefficients Γ_i, the integral on the left-hand side of (13) is equal to:

$$p\cdot\sum_{i=1}^{365} 24\cdot\Gamma_i.$$

The time-averaged unit variable cost, w, the time-averaged unit fixed cost, f and the capacity cost c, as defined in Section 3, yield that the right hand side of (13) reduces to:

$$w+\gamma+c\cdot\Delta \equiv LCOE.$$

The final step is to recognize that because $365\cdot\Gamma \equiv \sum_{i=1}^{365}\Gamma_i$, inequality (13) is satisfied if and only if:

$$p\cdot\Gamma \geq LCOE. \quad (14)$$

■

Proof of Proposition 2:

Since $\epsilon_i(\cdot)$ integrates out to 24 on the interval $[0, 24]$, the Co-Variation Factor Γ_i is greater than or equal to one whenever:

$$\int_0^{24} \mu_i(t)[\epsilon_i(t) - 1]dt \geq 0. \tag{15}$$

For notational convenience, we henceforth drop the index i. Let t^* denote the common point in time at which both $\epsilon(\cdot)$ and $\mu(\cdot)$ reach their peak. Furthermore, let t_1 and t_2 denote two points in time such that $t_1 < t^* < t_2$ and

$$\epsilon(t_1) = \epsilon(t_2) = 1.$$

The integral in (15) can be split into four regions of integration corresponding to the intervals $[0, t_1], [t_1, t^*], [t^*, t_2]$ and $[t_2, 24]$, respectively. We denote the respective integrals by S_1, S_2, S_3 and S_4. Thus

$$\int_0^{24} \mu(t)[\epsilon(t) - 1]dt \equiv S_1 + S_2 + S_3 + S_4.$$

Since $\epsilon(t) < 1$ on $[0, t_1]$ and $\mu(t)$ is increasing on $[0, t^*]$, we have:

$$S_1 \geq \mu(t_1) \cdot \int_0^{t_1} [\epsilon(t) - 1]dt.$$

Also

$$S_2 \geq \mu(t_1) \cdot \int_{t_1}^{t^*} [\epsilon(t) - 1]dt,$$

since $\epsilon(t) \geq 1$ on $[t_1, t^*]$. The fact that $\mu(\cdot)$ is decreasing on $[t^*, 24]$ yields the inequalities:

$$S_3 \geq \mu(t_2) \cdot \int_{t^*}^{t_2} [\epsilon(t) - 1]dt$$

and

$$S_4 \geq \mu(t_2) \cdot \int_{t_2}^{24} [\epsilon(t) - 1]dt,$$

If $\epsilon(t)$ is symmetric around $t^* = 12$, we conclude that:

$$\int_0^{12} [\epsilon(t) - 1]dt = \int_{12}^{24} [\epsilon(t) - 1]dt = 0$$

and therefore $S_1 + S_2 + S_3 + S_4 \geq 0$. On the other hand, if both $\epsilon(\cdot)$ and $\mu(\cdot)$ are symmetric around the common point t^*, then $\mu(t_1) = \mu(t_2)$ and therefore:

$$S_1 + S_2 + S_3 + S_4 \geq \mu(t_1) \cdot \int_0^{24} [\epsilon(t) - 1] dt = 0.$$

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